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March 3, 2016

Mr. Ken Harris, Supervisor
Division of Oil, Gas and Geothermal Resources
Department of Conservation
801 K Street, MS-24-02
Sacramento, CA 95814

Re: Comments on UIC Discussion Draft

Dear Mr. Harris:

This is in response to the request for input to the Draft UIC Regulations. Specifically, we would like to comment on Section 1724.10(j)(1), heretofore known as Standard Annual Pressure Test (SAPT).

In 2012 the Division started implementing an internally generated procedure to modify the requirements for the Standard Annular Pressure Test (SAPT). This changed the procedure promulgated by the 1990 Notice to Operators under which the testing had been conducted for 22 years. The Notice specified that the test was to be conducted to 200 psi above the maximum anticipated injection pressure that the wellbore casing would be subjected to; the new internal procedure specified that the test was to be conducted to "maximum allowable surface pressure (MASP), or 200 psi, whichever is greater". At the time that the Notice to Operators was promulgated, District 4 issued a memo to the operators that clarified that if a well had an injection tubing string, isolation packer and the annulus was vented, the casing wouldn't be exposed to injection pressure; thus the anticipated injection pressure that the casing would see would be zero (0) and it would only have to be tested to 200 psi. surface pressure.

When the Division implemented their new procedures in the field, several well casings failed the testing at these much higher pressures, resulting in the need for very costly repairs (usually involving the cementing of an inner casing). In other cases, operators who were unwilling to risk testing to the higher injection pressures had to curtail injection and thus shut-in production.

There is no regulatory basis for testing the casing at pressures as high as Maximum Allowable Surface Pressure (except in the specific case where the casing is directly exposed to injection pressure). These limits are not specified by any existing federal or state regulations applicable to California. Furthermore, the US Environmental Protection Agency (EPA) in its audit of DOGGR in 2011 specifically cautioned that testing older casing to such high pressures could cause unnecessary casing failures. The casing failures that were caused by the new DOGGR procedures since 2012 have proven this to be true.

The Division has allowed the filing of alternative procedures that provide for testing at pressures less than MASP while ensuring the continued verification of casing integrity. We have submitted such a procedure ourselves that provides for:

- Testing the annulus at 500 psi surface pressure (this being in increase from the 200 psi previously required).

- The casing annulus would be vented during normal operations in order to allow for leak detection and to prevent the casing from being pressurized if there were to be a leak.
- Testing frequency would be done every five years (or at a frequency specified by the Division).
- The injection well would be monitored for leakage daily.
- Injection could continue at the step rate test determined MASP without a reduction in pressure to below the SAPT test pressure.

The current Draft UIC regulations are a duplication of the internal 2012 DOGGR procedures; no allowance has been made for the incorporation of reasonable changes that have been accepted and incorporated into the "alternate procedures". We strongly recommend that the Division revise the draft language to incorporate procedures such as the one which we developed and submitted at the recommendation of DOGGR staff (see attached).

The Division should consider the following issues that the Draft UIC regulations as written could cause:

- How many injection wells would not be able to pass testing of the casing to full MASP? What would be the cost of repairing the damage caused? Would this be sufficient to warrant consideration of alternative procedures (such as those already submitted)?
- What existing regulations (Federal or State) that are applicable to California require the testing to the higher pressures that would be required under the Draft UIC regulations?
- What was the intent of the EPA's caution in the audit letter to DOGGR that testing to higher pressures such as MASP in older wells could cause more problems than they would solve? How has DOGGR applied this warning in their Draft UIC regulations?
- If injection wells were to be shut-in or operated at reduced capacity, what is the potential for reduction in production and the resultant impact on economics of existing operations?

The implementation of the Draft UIC regulation testing of the casing annulus to MASP could cause significant damage to existing infrastructure, with drastic impact on a very fragile industry at this time of low oil prices that in many cases are below normal operating costs. The consideration of alternative procedures such as those already negotiated should be allowed, while ensuring continuing safe and environmental responsible operations.

Sincerely,

Chris Hall

James C. (Chris) Hall
President

Attachment: Alternative Testing Procedure

Cc: Rock Zierman, California Independent Petroleum Association (CIPA)
Les Clark, Independent Oil Producers' Agency (IOPA)
Jerry Anderson, California Conservation Committee of California Oil & Gas Producers (CCCOGP)

ALTERNATIVE TESTING PROCEDURE

The following an "Alternative Plan" for the Standard Annular Pressure Test (SAPT) requirements that was submitted to DOGGR to meet their new requirements to test the casing at 500 psi:

1) **What pressure will be used for the SAPT requirements:**
   a. The SAPT test pressure of the wellbore casing will be 500 psi as measured at the surface.
   b. Since there is a downhole packer at the bottom of the injection tubing string and it is maintained in a leak free condition, the well bore casing is effectively isolated from the injection pressure to which the downhole formation is exposed; also, the casing annulus is vented to atmosphere. Therefore, the maximum anticipated surface pressure to which the casing will be exposed is 0 psi.
   c. The SAPT test should be conducted with a "Test Manifold" constructed for solely this purpose. It consists of the following:
      i. High pressure connection hose and inlet isolation valve to the well's injection line.
      ii. Manifold bleed valve used to reduce pressure on the manifold and casing.
      iii. Manifold pressure relief set at 550 psi to prevent over pressurizing the manifold or the casing annulus.
      iv. Manifold throttle valve and hose to be connected to the casing annulus vent; it is used to pressurize the casing annulus.
   d. In accordance to the Notice to Operators, the SAPT should be conducted at the test pressure (in this case 500 psi) for at least 15 minutes with no greater than 10% psi drop (50 psi) in pressure.

2) **What form of back-up or safety or pressure relief or other system(s) will be employed:**
   a. For Normal System Operation: The casing annulus vent (between the casing string and the injection tubing) should be left open to provide evidence of injection tubing string or packer leakage and to prevent the casing annulus from building up pressure above 0 psi at the surface if there were leakage.
   b. Neither the Test Manifold nor the wellbore casing should be pressurized to greater than 550 psi; the 550 psi relief valve installed on the manifold is the backup safety system during the test. The vented annulus is the back-up safety mechanism during the remainder of the year.

3) **The pressure at which the system(s) will be set to operate:**
   a. The casing annulus should always be vented at the surface in order to maintain 0 psi.
   b. During SAPT tests, the well bore casing should not be exposed to pressures in excess of 550 psi.

4) **How often and with what method will the system(s) be tested and reported to the Division:**
   a. Since the casing annulus pressure is maintained at 0 psi surface pressure and is inspected daily, no additional testing of the system (other than the SAPT) is required. Likewise, no reports would be required to be made to the Division unless system leakage was detected, in which case injection would be discontinued until repairs

could be made. Pumper's Daily inspection records would be available for inspection by the Division upon request.

5) **<u>How will the system(s) be monitored, such as use of a SCADA or other monitoring method and frequency:</u>**
   a. The casing annulus surface vent should be checked daily by the pumper in order to verify that the vent is open (indicating no pressure in the annulus) and that there is no indication of leakage past the packer or tubing string. Evidence of leakage would be evidence of failure of the containment of the injection pressure to the injection system; the well would be shut-in until repairs were made.

6) **<u>How will any casing integrity or pressure issues be reported to the Division:</u>**
   a. Surface Annular Pressure Tests would be conducted as required by DOGGR. They would be witnessed by a Division representative.

7) **<u>The schedule by which the Plan will be installed and functional:</u>**
   a. The injection wells will be tested at a frequency as required by the Division of Oil Gas and Geothermal Resources (DOGGR).